Attachment 1: Pipeline Supply Model Inputs and Assumptions

New Jersey Transition Incentive Supporting Analysis and Recommendations – August 2019

Prepared by Cadmus and Sustainable Energy Advantage for the NJ Board of Public Utilities, August 2019

Incremental Supply Forecast

Forecasting Installed Capacity

- Incremental installed capacity per month is assumed to follow historic averages by size bin and EDC, displayed below
  - We scale these base installation rates upwards during the end of 2019 to reflect developers' response to expiring federal tax credits

Average monthly installations in 2018 (MW)					
Size Bin	**JCP&L**	**ACE**	**PSE&G**	**RECO**	**Total (MW)**
<25 kW	3.1	3.6	4.4	0.1	11.3
25 - 250 kW	0.6	0.4	0.9	0.0	2.0
250 - 500 kW	0.3	0.4	1.1	0.1	2.0
500 - 1000 kW	0.3	0.2	1.5	0.1	2.1
1000 - 2000 kW	0.3	0.1	1.5	0.0	1.8
2000 - 5000 kW	0.6	0.5	0.7	0.0	1.8
5000+ kW	3.1	0.0	1.0	0.0	4.1
				Grand Total	25.1

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Incremental Supply Forecast

Forecasting Installed Capacity

- Each month's build rate is constrained by the pipeline capacity (after de-rates), per size bin
- To calculate this on a rolling basis, we net out the capacity of projects installed against an application rate based on the last six months of applications, per size bin
  - This rate is adjusted to account for attrition (assuming 30% of projects will not reach PTO) and to account for outlier months (April saw over 60 MW of grid supply projects apply)
- The base application rate is scaled down prior to the release of the TI program rules (assumed October 2019) to reflect developer uncertainty

Assumed base application rate (MW)	
Size Bin	**Total (MW)**
<25 kW	7.1
25 - 250 kW	3.4
250 - 500 kW	2.3
500 - 1000 kW	3.4
1000 - 2000 kW	6.0
2000 - 5000 kW	3.3
5000+ kW	5.5
Total	31

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Incremental Supply Forecast

De-rating projects with unusual delays

- For the purposes of accounting incremental capacity coming online, we apply de-rates to projects with unusual delays in their SRP milestones
- First, we apply a de-rate to projects who are expected to have already achieved PTO (based on the results of the cohort analysis, see next slide)
- Second, we apply a de-rate to projects that are operational but have not been deemed complete
    - After consulting with TRC, we believe many of these older projects are generally associated 3rd Parties that are now out of business

Delay De-rate for Projects not Operational Past Expected PTO Date		
Days passed from imputed PTO date*	**De-rate**	**MW associated with each de-rate**
60	1	480.0
90	0.9	43.2
120	0.8	38.9
150	0.75	51.1
180	0.7	5.8
210	0.65	11.3
240	0.6	2.7
270+	0.5	24.5

*Compared to the last date accounted for in the May Pipeline Report (5/31/19)

Delay De-rate for Operational Projects without SRP Completion		
Year PTO was reached	**De-rate**	**MW associated with each de-rate**
2019	1	2,812.0
2018	0.6	24.0
2017	0.2	3.9
2016 - 2010	0	17.6

Cohort Analysis

Evaluating expected time to PTO by project size

Size Bin	Sample Size	Average Time Accepted -> PTO (days)	Number Assumed for Modeling (days)
<25 kW	92	247.1	230
25 - 250 kW	289	200.5	230
250 - 500 kW	44	254.8	230
500 - 1000 kW	38	215.4	230
1000 - 2000 kW	12	258.9	320
2000 - 5000 kW	6	120.4	320
5000+ kW	10	584.0	320

Given similar numbers, these categories were averaged to remove statistical noise

Due to a their small sample size, these size bins were averaged

Cohort Analysis

Evaluating Scrub Rate by project size

Size Bin	# of Projects Accepted In Pipeline as of November 2016	# of Projects with PTO or still in Pipeline as of Dec 2018	Scrub Rate	Scrub Rate Adopted for Modeling
<25 kW	86	60	30%	30%
25 - 250 kW	267	172	36%	30%
250 - 500 kW	41	30	27%	30%
500 - 1000 kW	36	26	28%	30%
1000 - 2000 kW	10	7	30%	30%
2000 - 5000 kW	6	5	17%	35%
5000+ kW	9	4	56%	35%

Due to a their small sample size, these two size bins were averaged

Take away: There are a total of 657 MW in the pipeline as of the May 2019 report. Per the scrub rate (in combination with de-rates for project delay and expiration) we estimate that 453 MW ultimately will reach PTO and produce SRECs

Incremental Supply Forecast

Capacity Factor Designations

- Each project is assigned a Resource Class based on its customer type and size, which then determines its capacity factor
- Currently, capacity factors per Resource Class are uniform across all years, however our model will accept variation across years

Resource Class	Assumed Capacity Factor
Resource Class A	15.0%
Resource Class B	14.5%
Resource Class C	14.0%
Resource Class D	13.5%
Resource Class E	13.0%

Size Bin	Commercial	Farm	Government Facility	Municipality	Non-Profit	Public University	Residential	School
>25 kW	D	D	E	E	E	E	E	E
25 - 250 kW	D	D	D	D	D	D	E	E
250 - 500 kW	D	D	D	D	D	D	D	D
500 - 1000 kW	C	C	D	C	C	C	D	D
1000 - 2000 kW	B	B	C	B	B	C	C	C
2000 - 5000 kW	B	B	B	B	B	B	B	B
5000+ kW	A	A	A	A	A	A	A	A

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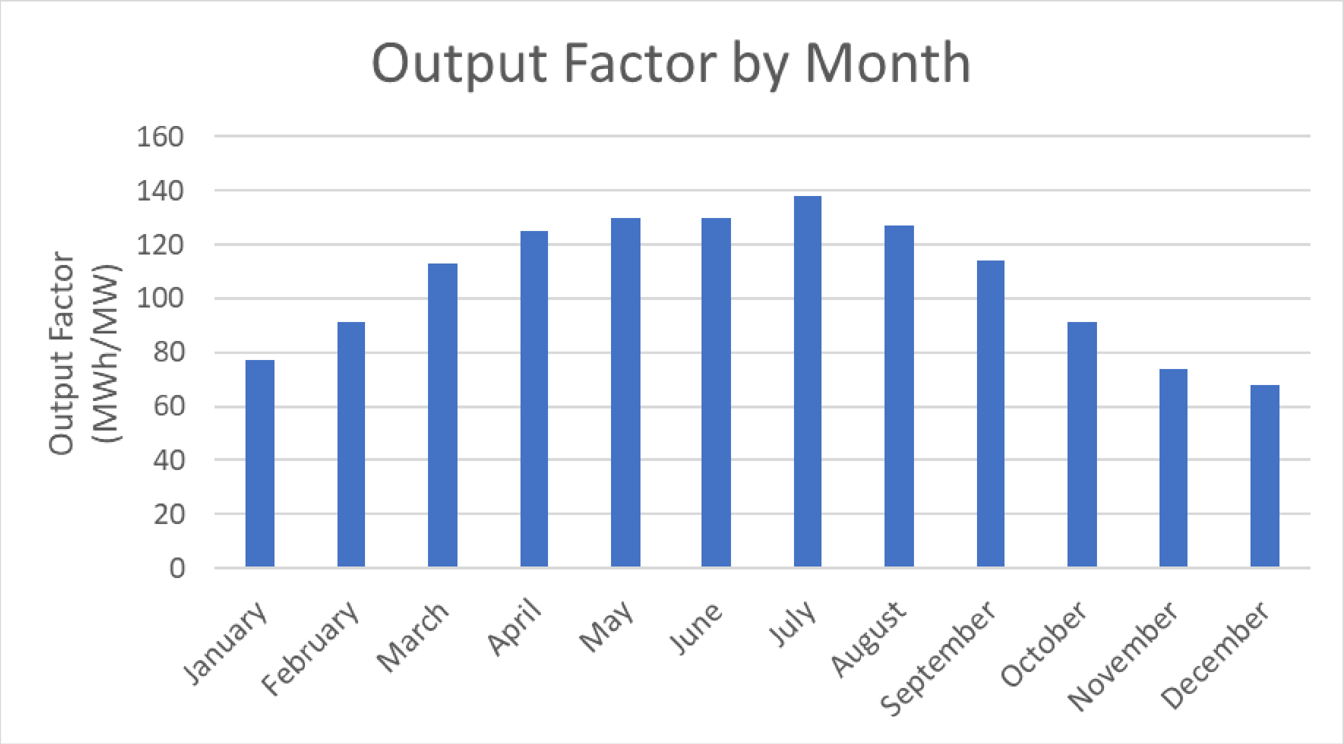
Incremental Supply Forecast

Scaling monthly production

- Yearly capacity factors are scaled based on an index of each month's output factor to determine monthly production



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Incremental Supply Forecast

Historic SREC Production: QC of Actual vs. Modeled

- To forecast the monthly production of solar facilities that are currently installed, we modeled the incremental supply of SRECs from 2004-present
- By comparing our model's estimate to actuals, we assessed the accuracy of our forecast going forward
- Results are generally strong, with more significant overestimation in 2018
- We attribute the overestimation in 2018 to system owners that have not yet claimed the RECs from production that has already occurred, meaning they do not appear in PJM GATS. Thus, we anticipate that the actual will be revised upwards with time.

Energy Year	2014	2015	2016	2017	2018
Modeled Estimate	1,384,929	1,652,917	1,855,646	2,231,811	2,704,829
Actual	1,363,095	1,623,269	1,891,439	2,235,989	2,532,728
Estimate/Actual	102%	102%	98%	100%	107%

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Calculating 5.1% Attainment

- To estimate the attainment of when 5.1% of the kWh sold in NJ is from solar electric power generators connected to the distribution system we:
  - Estimate retail electricity sold going forward based on the load obligated under the most recent RPS compliance report: 73,679,057 MWh (the denominator)
  - Estimate the trailing 12 month average of solar generation by multiplying the cumulative installed solar capacity for the previous twelve months by a corresponding solar output factor for each month assuming 1200 MWh/MW_{DC} in annual production (the numerator)
- This method results in 5.1% being attained in September of 2020

Legacy SREC Supply/Demand Model Inputs and Assumptions

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Statistical Relationship of Banked SRECs & SREC Prices

It's Strongly Negative

Correlation Coefficients of	Total SRECs Banked (MWh)	Weighted Avg. SREC Trade Price During EY ($/MWh)	SREC Price (% of SACP)	SREC Price (% of SACP EY+1)	Banked SREC (% of EY Demand)
Total SRECs Banked (MWh)	100%				
Weighted Avg. SREC Trade Price During EY ($/MWh)	-93%	100%			
SREC Price (% of SACP)	-35%	33%	100%		
SREC Price (% of SACP EY+1)	-81%	77%	73%	100%	
Banked SREC (% of EY Demand)	70%	-60%	-88%	-85%	100%

Regression Statistics: Dependent Variable = Avg. SREC Price as % of SACP (n=7)	Coefficients	Standard Error	t Stat	Interpretation
Intercept	0.792	0.050	15.695	If Banking is at 0%, then predicted Avg. SREC Price will be 79.2% of SACP
Banked SRECs (as % of EY Demand)	-0.712	0.168	-4.232	For each 1% increase in banked SRECs (as % of EY Demand), Avg. SREC Prices will drop by 0.712% of the SACP level

Regression used as basis of SREC Price Forecasts, with "in practice" model capping SREC prices: Ceiling @ SACP; Floor @ Assumed Class I REC Price (i.e., $7)

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Legacy SREC Load Exemptions

- Per the December 28, 2018 BPU Order in two BGS Dockets, BGS providers are partially exempt from increases in Solar RPS requirements as included in the Energy Act of 2018
  - Top table to the right displays the default general requirements and the lower requirements for BGS providers w/ exempt load through EY 2021
- We assume given the three-year laddering of BGS procurement that the exempt load of BGS providers decreases by 1/3 each year and is 0% starting EY 2022 for the remainder of the program
  - Lower table to the right displays inputs and the final row results of the average in practice SREC requirements taking into account BGS providers with exempt load being allocated to the following two energy years in equal proportions

Dates	Requirement Type	Solar	Class I	Class II
6/1/2018-5/31/2019	General Requirement	4.30%	14.175%	2.50%
	Req't for BGS Providers w/Exempt Load	3.29%	14.175%	2.50%
6/1/2019-12/31/2019	General Requirement	4.90%	16.029%	2.50%
	Req't for BGS Providers w/Exempt Load	3.38%	16.029%	2.50%
1/1/2020-5/31/2020	General Requirement	4.90%	21.00%	2.50%
	Req't for BGS Providers w/Exempt Load	3.38%	21.00%	2.50%
6/1/2020-5/31/2021	General Requirement	5.10%	21.00%	2.50%
	Req't for BGS Providers w/Exempt Load	3.47%	21.00%	2.50%
6/1/2021-5/31/2022	General Requirement	5.10%	21.00%	2.50%

Energy Year	EY 2019	EY 2020	EY 2021	EY 2022	EY 2023
Statutory Solar Req't	4.30%	4.90%	5.10%	5.10%	5.10%
Req't for BGS Providers w/Exempt Load	3.29%	3.38%	3.47%	5.10%	5.10%
% Share of BGS Using Exemptions	100%	66.67%	33.33%	0%	0%
% Share of BGS of Retail Load	52%	52%	52%	52%	52%
% Share of BGS Not Exempt	0%	33.33%	66.67%	100%	100%
In practice avg. SREC Req't, taking into exempt load	3.77%	4.65%	5.35%	5.51%	5.24%

CREST Cost of Energy Model

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(Very) Simplified Representation of CREST Cost of Energy Model Calculation of "Cost of Entry"

Net Present Value (NPV)/ Discounted Cash Flows Resulting From:

PV Total Capital and Operating Costs (Various, 2019-2021 COD)

Compounded/Grossed-Up by…

Risk-Adjusted Financing Costs & Taxes (Various Terms, 2019-2021 COD)

LESS…

Expected Revenue/Federal Tax & Depreciation Benefits During and After Incentive Term (2019-2021 COD)

All Divided By…

PV Performance over Useful Life (MWh derived from Degradation-Adjusted Capacity Factor, 2019-2021 COD)

Put it all together and you get…

Cost of Entry/ "Incentive Cap Values" by Market Segment ($/MWh)

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Subdividing the Market for Modeling

- Market divided into 96 distinct "Supply Blocks", comprised of
- 24 distinct project configurations expected to come online in New Jersey through 2030, including
  - <=25 kW (residential & small C&I)
  - Ground Mounted
  - Building Mounted, including LMI
  - Landfill/Brownfield
  - Community Solar (both Ground and Building Mounted), including LMI
  - 3 Solar Carport configurations **(Not Included in Draft Analysis due to data availability – will be included in next round)**
- 4 Utility Groups
  - Atlantic City Electric (ACE)
  - Jersey Central Power & Light (JCP&L)
  - Public Service Electric & Gas Company (PSE&G)
  - Rockland Electric (RECO)
- 2 Ownership Structures
  - 3rd Party
  - Private Host-Owned

Draft PV Cost Analysis: Approach

- The consulting team utilized NJ-customized Cost of Renewable Energy Spreadsheet Tool (CREST) Model (a tool Sustainable Energy Advantage, LLC developed for the National Renewable Energy Laboratory (NREL))
- Purpose of NJ CREST: Establish incentive requirement (a/k/a "cost of entry") for NJ solar projects through 2030 (i.e., "incentive cap value")
    - For Transition Incentive (TI) purposes only: model 2019-2020, to capture projects currently in development that will be eligible for Transition Incentive "program"
- Standard (and customized) modeled inputs in NJ CREST include
    - Installed Costs
    - (If not already included in Installed Cost values) Interconnection Costs
    - Financing Costs (interest on term debt, debt tenor, % of debt, after-tax equity IRR, development and fees (if not captured in equity return)
    - Non-Community "Vanilla" Solar O&M
    - Specialized Incremental Community Solar O&M (ongoing customer servicing/retention costs)
    - Project Management Costs (incl. incremental Community Solar fixed upfront costs)
    - Land Lease
    - Property Tax/PILOTs
    - Financing Costs (interest on term debt, debt tenor, % of debt, after-tax equity IRR, development and fees (if not captured in equity return)
    - Changes (for most of the above) through 2030

Highlights of Draft PV Cost/Performance Assumptions

- Low, Base and High installed cost estimates (based on NJ SRP data) were set at the 25th, 37.5th and 50th percentiles, in order to 1) simulate outcomes associated with a program intended to reward lower-cost projects and 2) to correct for potential bias associated w/self-reported industry installed cost figures in SRP data
  - Costs assumed to decline in all cases through 2030 based on custom internal index based on industry and 3rd-party research, ranging from ~5%/yr in Low Cost cases to ~1%/yr in High Cost cases
- Interconnection costs assumed to vary along 25th-50th-75th continuum based on database of MA/RI costs (NJ-specific costs not obtained prior to draft modeling exercise)
  - Costs assumed to increase at a range between EIA's AEO 2019 T&D forecast for NJ in High cases and forecasted CPI in the Low Cost case
- Project performance based on location in Trenton, NJ (at near the latitudinal center of the state)
- Capacity factors at non-optimal tilts/azimuths assumed for <=25 kW, Building Mounted and Landfill/Brownfield projects (given that typical sites do not offer optimal conditions)
- 1% incremental improvement over time in Year 1 capacity factor
  - E.g., if 2019 COD assumption = 15.00%, 2020 COD assumption = 15.15%
- Annual degradation assumed at 0.5% as default

2019 Draft Cost Assumption Highlights

Project Category	Modeled Size Range (kW_{DC})	Yr 1 Capacity Factor (PVWatts)	Installed Cost Range ($\$/kW_{DC}$)
<=25 kW	6.5 kW-13.2 kW	15.30%	$2,724-$3,326
Building Mounted	250 kW-2 MW	15.40%	$1,640-$2,377
Ground Mounted	500 kW-10 MW	15.90%	$1,550-$2,010
Community Solar	1 MW-5 MW	15.40%-15.90%	$1,640-$2,000
Low/Moderate Income	250 kW-1 MW	15.40%-15.90%	$1,710-$2,377
Landfill/Brownfield	1 MW-5 MW	15.40%-15.60%	$1,636-$2,275
Grid Supply	5 MW-10 MW	15.90%	$1,550-$2,000

Source for Installed Cost Data: NJ BPU Office of Clean Energy SRP Registrations
Note: Installed cost includes interconnection costs

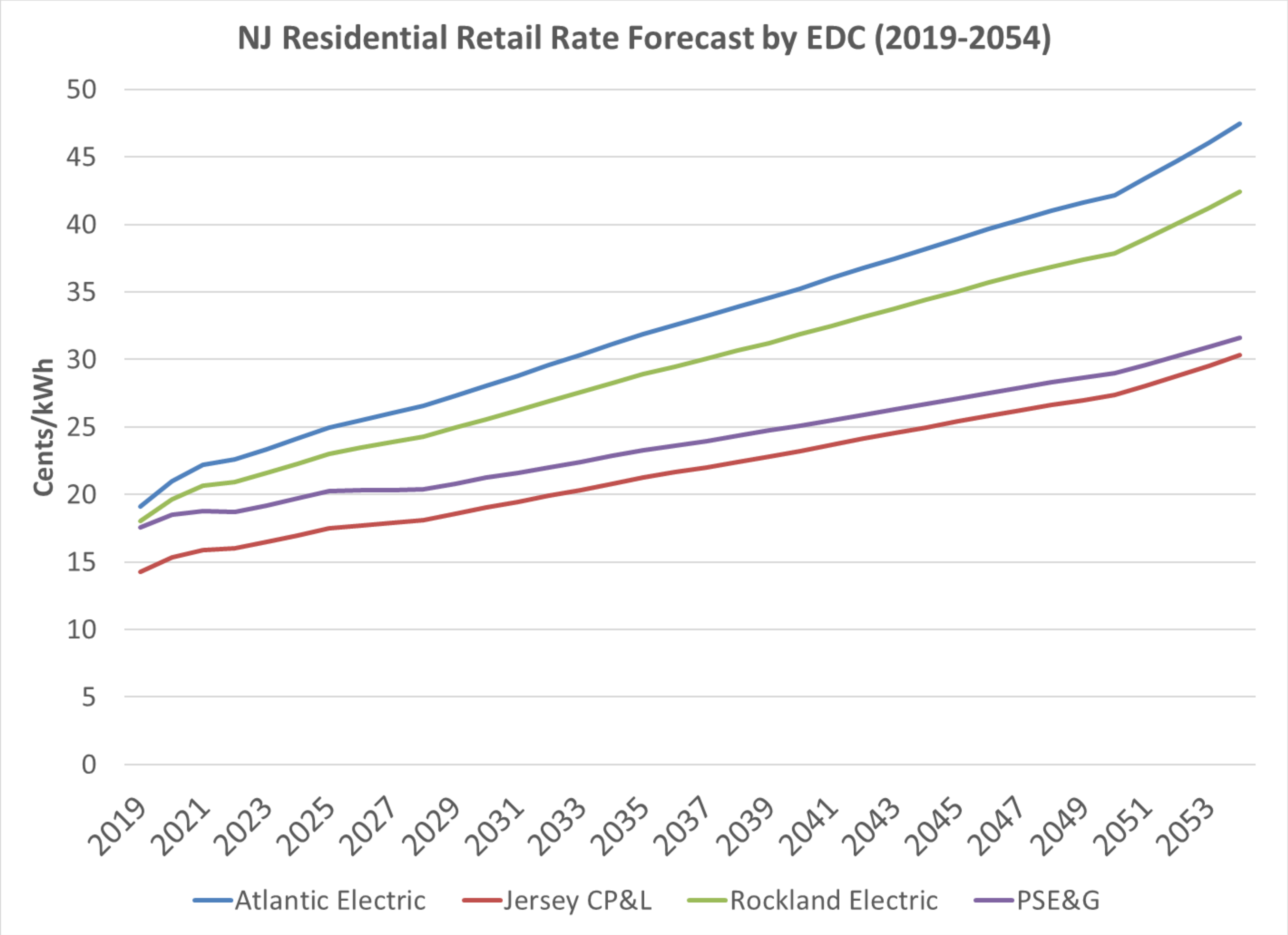
Highlights of Draft PV Financing/Tax Assumptions

- The orderly phase-down of the Investment Tax Credit (ITC) under current law through January 1, 2022 (to 0% for host-owned residential systems and 10% for all others)
  - **Simplifying assumption: Transition Incentive Systems expected to reach COD after 1/1/2020 are assumed to "safe harbor" their tax credits at 2019 value (30%)**
- Increased usage of the bonus depreciation (100% thru 2023, declining 20%/yr thereafter) provisions of the Tax Cuts and Jobs Act of 2017 as tax credit value fades
- Pro forma NJ Class I REC value of $5/MWh assumed after incentive term (intended to represent highly discounted value)
- Increasing debt shares in capital stack (as tax equity shares fall)
- All applicable NJ tax rates and credits relevant to solar PV projects (or averages where appropriate)
- No utilization of PSE&G Solar Loan Program (since program eligibility/access to loan funds not assured)

Non-Incentive Compensation Assumptions (Net Metering/Wholesale, 2019-2054)

- We assume that all projects < 5 MW, and CSS projects up to 5 MW, are net metered
- These projects' non-incentive compensation is determined using the following rate class designations:
  - Projects <=25 kW are assumed to be on a residential rate class
  - Projects that are 250 kW – 500 kW or CSS of any size are assumed to be on a small/medium C&I rate class
  - Projects >= 1 MW are assumed to be on a large C&I rate class
- Non-CSS projects that are >= 5 MW are assumed to receive compensation on the wholesale market (energy + capacity)
- Net metering/wholesale values are forecasted thorough 2054 (*please see SWS1 presentation for rate forecast methodology*)

Forecasted Net Metering/Wholesale Values (2019-2054)



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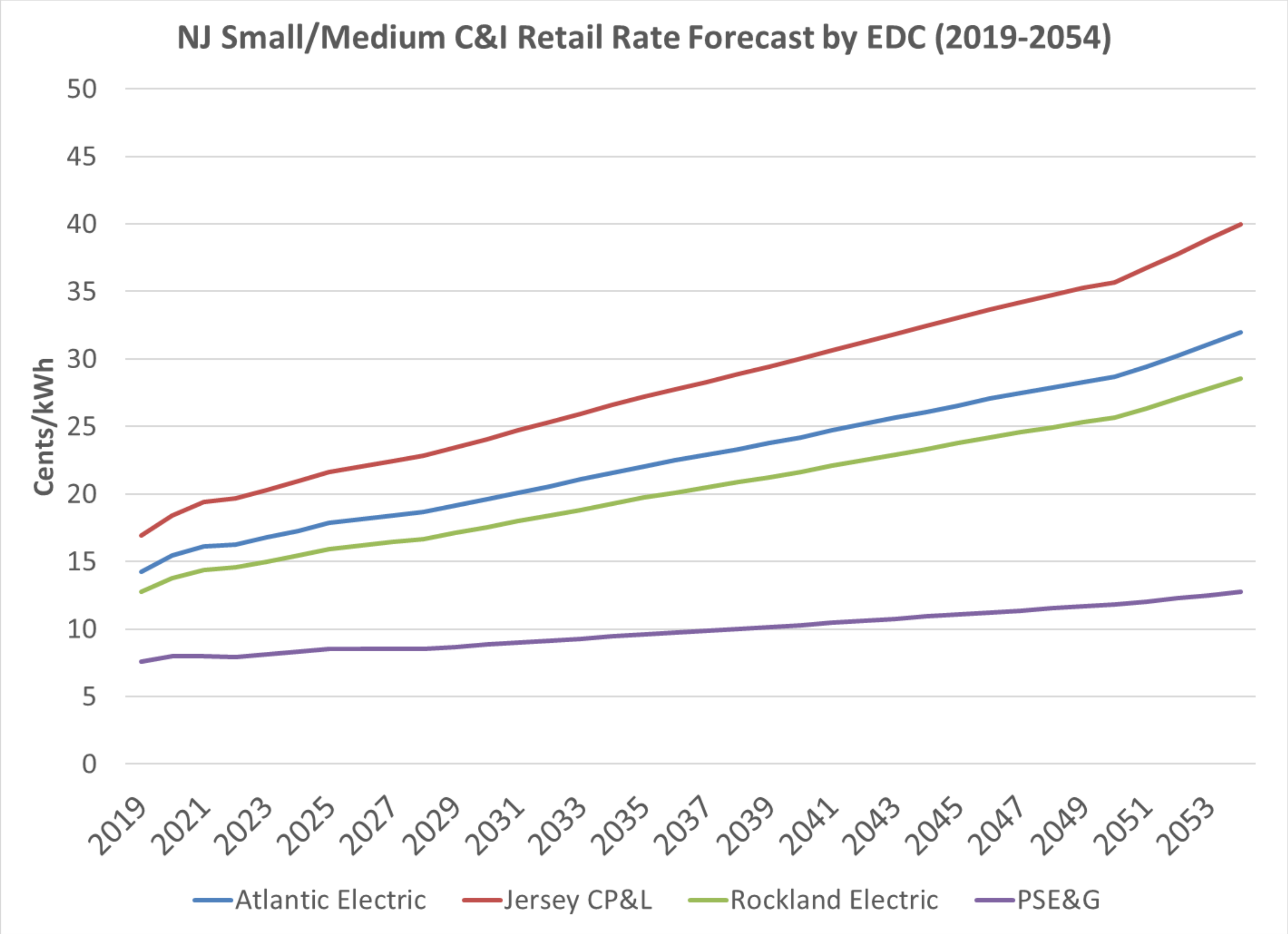

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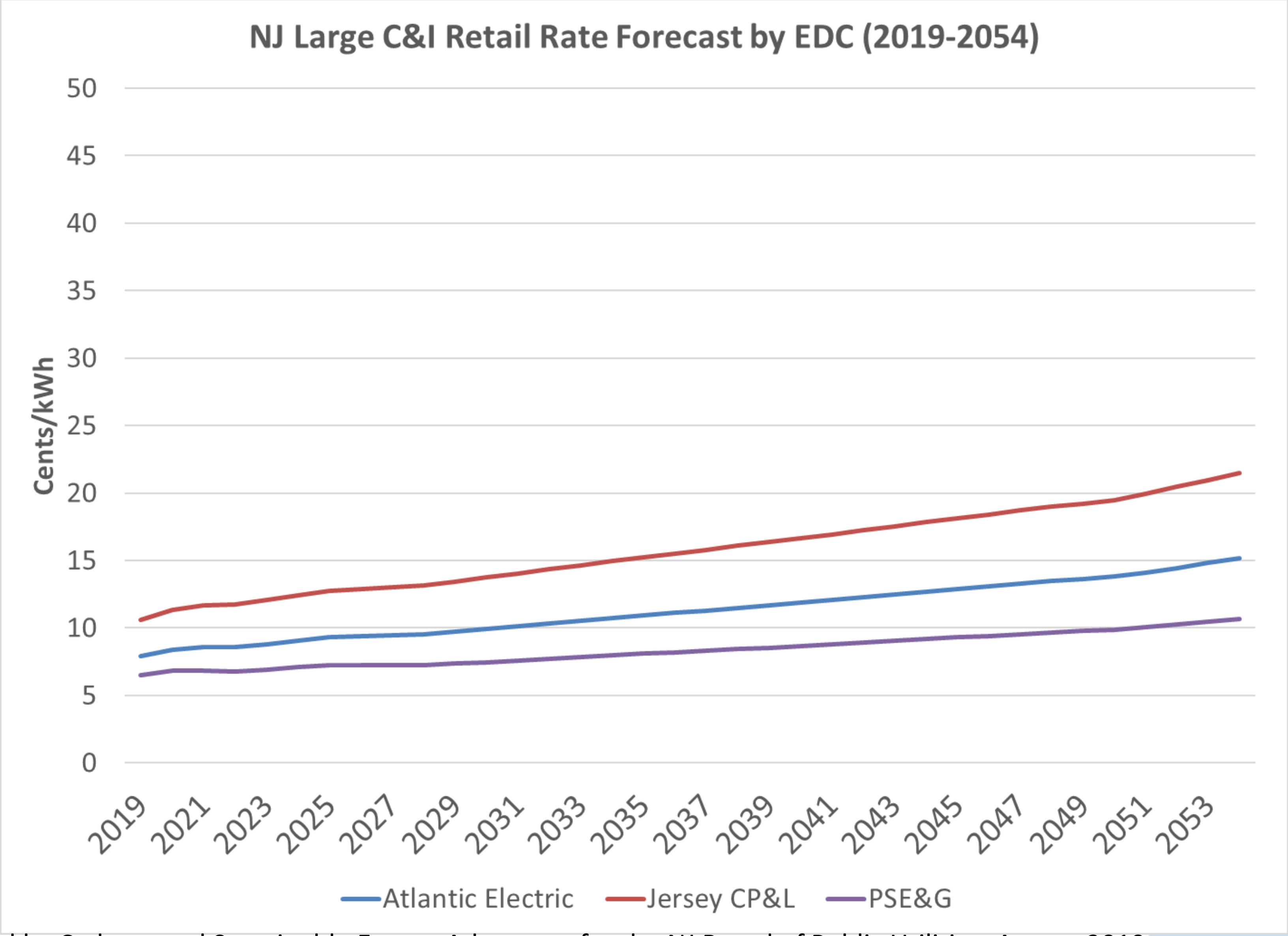

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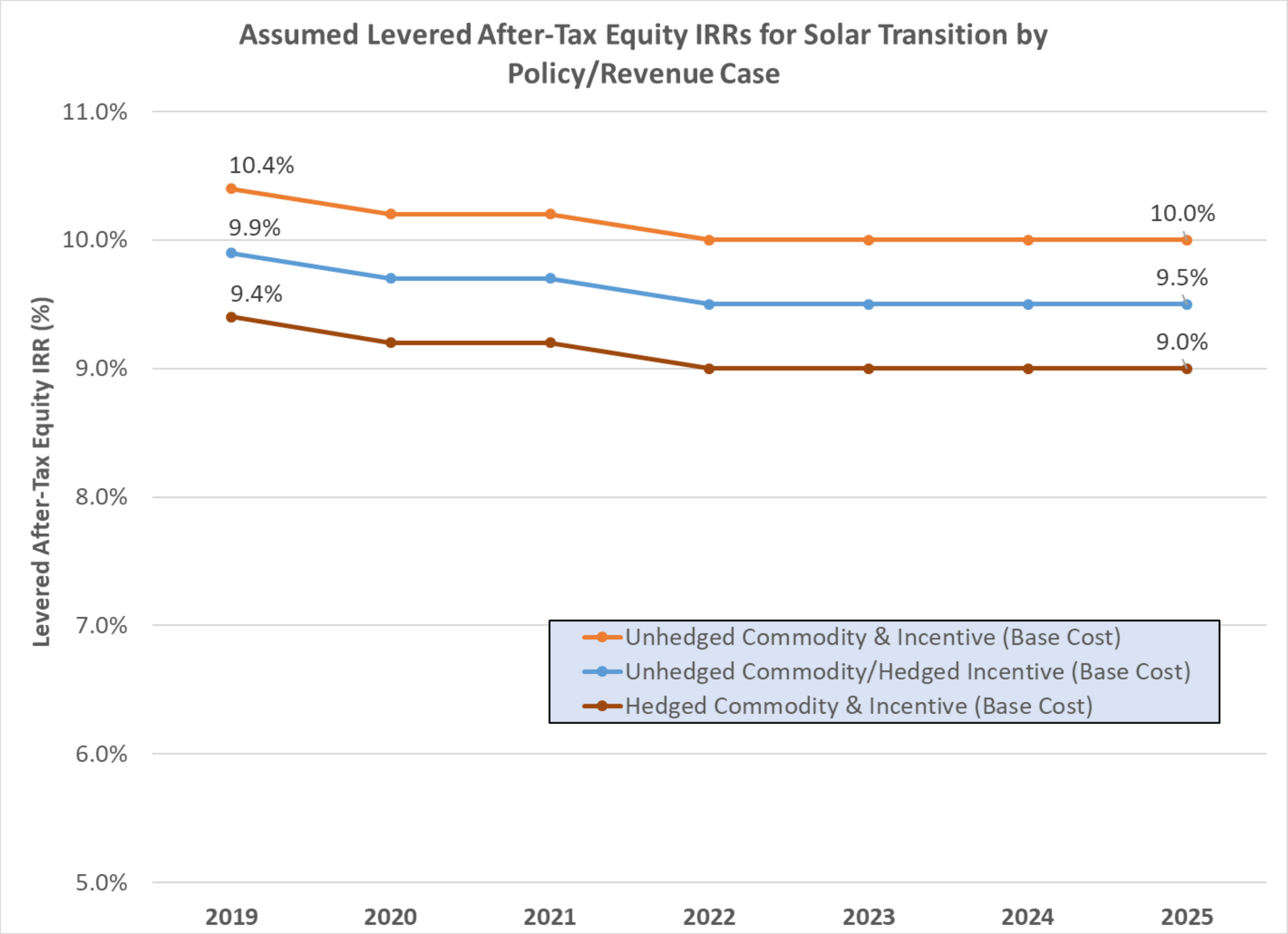
Interaction of Incentive Type and Financing/Revenue Risk

- The unit cost (in $/MWh) of the incentives paid out to a given type of distributed solar project varies based on
  - The term of the incentive
  - The certainty of the "commodity" revenue (in NJ's case, net metering) and incentive revenue from a Transition Incentive or Successor Program incentive (and conversely the risks associated w/each)
- For modeling purposes, distributed solar incentive policies tend to fall into three broad categories
  - **Unhedged Commodity & Incentive** (e.g., the Legacy SREC program)
  - **Unhedged Commodity/Hedged Incentive** (e.g., fixed REC programs such as CT LREC/ZREC)
  - **Hedged Commodity & Incentive** (e.g., fully bundled, similar to MA SMART/RI REG program)
- A more hedged revenue stream can reduce financing (and thus overall) costs by
  - Reducing overall cost of equity (by reducing risk)
  - Increasing the potential debt share a project can take on
  - Increasing the overall debt term/"tenor" (mitigating the impact of the cost of debt on the value of the project)
- Financing cost savings associated with fixing certain project revenue streams are amplified during & after ITC phase-out (see next page)

Interaction of Incentive Type and Financing/Revenue Risk: Illustrative Financing Assumptions by Policy/Revenue Case



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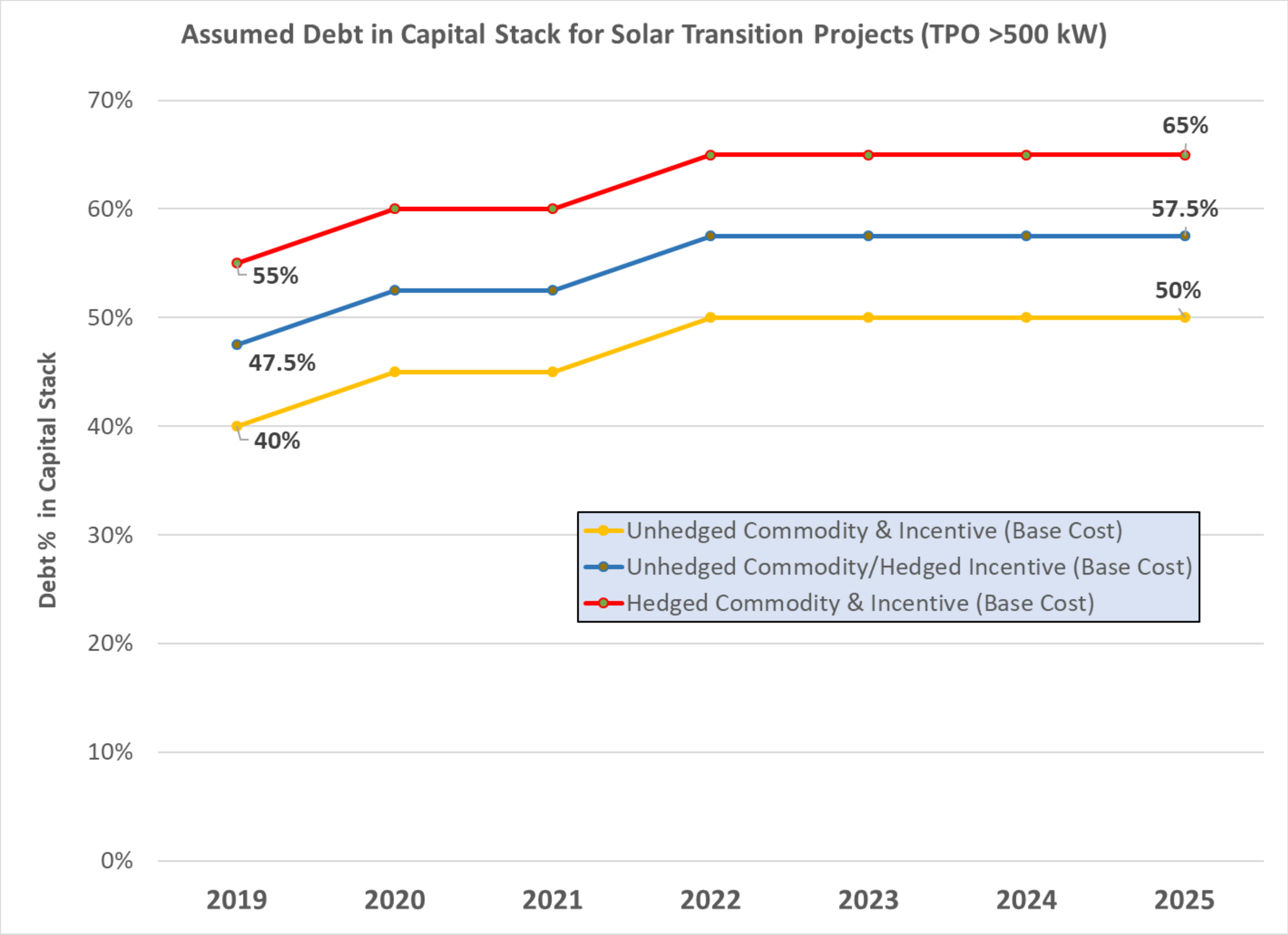

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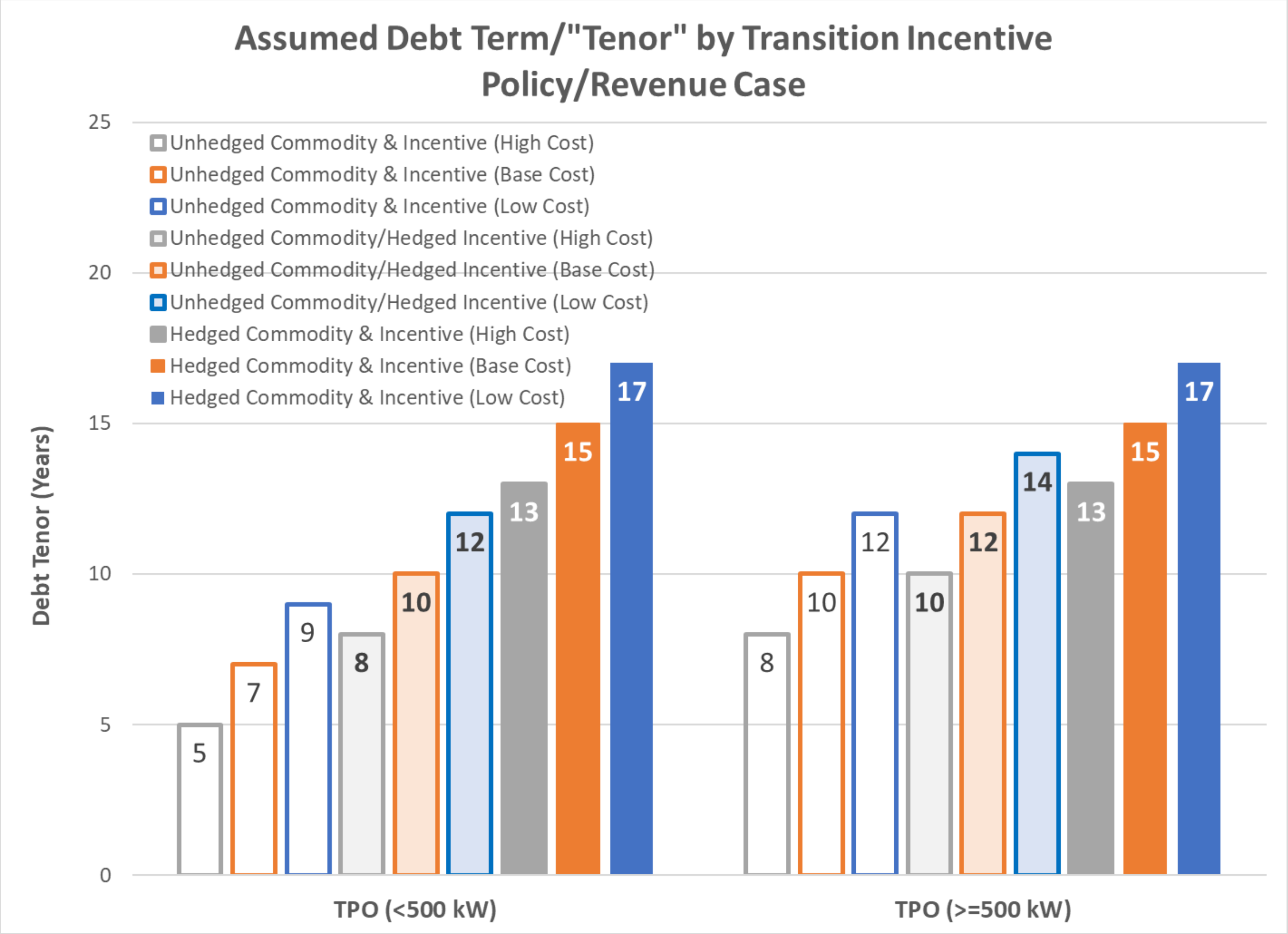

Additional Cost of Entry Analysis Methodology Details and Sources

Prepared by Cadmus and Sustainable Energy Advantage for the NJ Board of Public Utilities, August 2019

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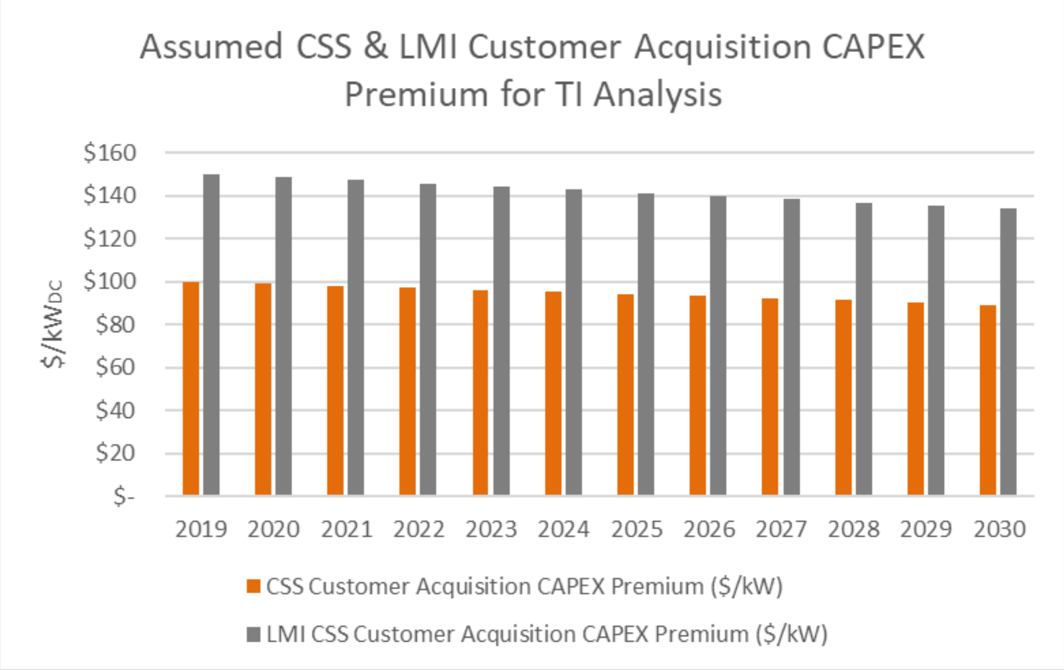
Detailed Draft NJ 2019 CAPEX Premium Assumptions (Community Solar, LMI and Landfill/Brownfield) & Interconnection

- **Community Solar**
  - Assumed $100/kW CAPEX premium over similarly-situated ground or building mounted project, declining through 2030 (shown at right)
  - ***Source:*** *Industry feedback from multiple sources, including [RI Renewable Energy Growth 2019 Ceiling Price Development Process]*
- **Low/Moderate Income (LMI)**
  - Assumed 50% increase on top of Community Solar CAPEX premium on similarly-situated ground or building mounted project (representing average of TPO/Host responses, and declining through 2030, as shown at right)
  - ***Source:*** *Ratio analysis based on industry responses from [Developing a Post-1,600 MW Solar Program]*
- **Landfill/Brownfield**
  - **For 1 MW modeled size:** 5% premium over similarly situated ground mounted project
  - **For >1 MW modeled size:** 15% premium over similarly-situated ground mounted project
  - ***Source:*** *Ratio analysis based on industry responses from [Developing a Post-1,600 MW Solar Program]*
- **Interconnection**
  - Assumed to be included in costs reported in SRP data, but backed out and increase at rates ranging between EIA's AEO 2019 T&D forecast for NJ in High cases and forecasted CPI
  - **Average IC Costs:** $133/kW
  - ***Source:*** *National Grid in MA/RI, and utilized in [RI Renewable Energy Growth 2019 Ceiling Price Development Process] (expectation is that NJ specific costs will come from participant survey and/or EDCs)*



NOTE: All kW numbers are in nameplate direct current (DC)

Detailed Draft NJ 2019 OPEX Assumptions (1)

- **"Vanilla" Fixed O&M**
  - **Initial Estimate:** Assumed $35/kW for <25 kW, $14/kW for 25-500 kW, and $12/kW for >500 kW
  - **CSS O&M Premium:** Assumed $25/kW incremental to base O&M costs
  - ***Source:*** *Industry feedback gathered in kWh Analytics' 2019 Solar Risk Assessment and RI Renewable Energy Growth 2019 Ceiling Price Development Process*
- **Inverter Replacement**
  - **Replacement year:** Assumed inverter replacement necessary every 13 years
  - **Replacement cost:** Assumed $50/kW (in replacement year) for <25 kW, $21/kW for >25 kW
  - ***Source:*** *Industry feedback gathered in RI Renewable Energy Growth 2019 Ceiling Price Development Process*
- **Insurance**
  - Assumed 0% of total costs for <25 kW, 0.27% for 250 kW, and 0.45% for >250 kW
  - ***Source:*** *Industry feedback gathered in RI Renewable Energy Growth 2019 Ceiling Price Development Process*
- **Project Management Costs**
  - Assumed $17/yr for <25 kW, $1,625/yr for 250 kW, $3,000/yr for 250-1000 kW, $5,000/yr for 1-5 MW, and $6,337/yr for >5 MW.
  - ***Source:*** *Industry feedback gathered from NJ Cost and Technical Potential survey and through RI Renewable Energy Growth 2019 Ceiling Price Development Process*
- **Site/Land Lease Costs**
  - Assumed $0/yr for projects <25 kW, $10,000/yr for 250 kW, $20,000/yr for 250-1000 kW, $55,000/yr for 1-5 MW, and $65,000/yr for >5 MW.
  - The land lease costs for carports are decreased by 37% to reflect the diminished opportunity cost of these projects.
  - ***Source:*** *Industry feedback gathered from NJ Cost and Technical Potential survey and through RI Renewable Energy Growth 2019 Ceiling Price Development Process, adjusted for the difference between RI and NJ land costs according to the USDA Land Values 2018 Summary report*

Detailed Draft NJ 2019 OPEX Assumptions (2)

- **Indexed OPEX Growth During Project Life:**
  - All above OPEX categories assumed to escalate 2%/year
- **Change in O&M/Project Management/Insurance Costs Over Time**
  - Assumed to decline at rates observed in *2018 Annual Technology Baseline (ATB)*
- **Property Tax/PILOT Costs**
  - **Initial Estimate:** Assumed $5/kW for projects 5 MW or greater
  - **Change Over Time:** Assumed to be constant
  - ***Source:*** *Industry feedback gathered in RI Renewable Energy Growth 2019 Ceiling Price Development Process*
- **Decommissioning**
  - **Decommissioning Cost:** Assumed $20/kW for all projects
  - **Bond Expense for Decommissioning (%):** Assumed 2% of decommissioning costs for all projects
  - **Change Over Time:** Assumed to be constant
  - ***Source:*** *Industry feedback gathered in RI Renewable Energy Growth 2019 Ceiling Price Development Process*

Detailed Draft NJ Solar Financing Assumptions (1)

- **Debt %**
  - **Initial Estimate (Associated w/Fully Unhedged):** Projects w/no long-term contract or tariff cannot exceed 35% (NREL estimate associated with Large Distributed PV Portfolios, and NJ is largest TPO state in the country) for <=250 kW systems (w/40% for systems >250 kW, since larger systems are usually associated w/more creditworthy TPO borrowers)
  - **Change Over Time:** Share of debt increases up to 10% of total capital costs by the time ITC fully disappears, and 5% during ITC step-down period (industry assumed to desire to mitigate costs as ITC fades out)
  - **High/Low Variance Within Policy/Revenue Cases:** Assumed +/- 5%
  - **TPO/Host Variance:** None
  - **Change Between Policy/Revenue Base Cases:** +7.5% for Unhedged Commodity/Hedged Incentive (fixed REC, translating to 42.5% for <25 kW and 47.5% for >25 kW), +15% for Hedged Commodity & Incentive (50% for <25 kW and 55% for >25 kW, in line w/RI 2019)
- **Lender's Fee**
  - 2% for TPO, 0% for Host (from *RI Renewable Energy Growth 2019 Ceiling Price Development Process*)

Detailed Draft NJ Solar Financing Assumptions (2)

- **Interest on Term Debt**
  - **Initial Estimate (for all cases):** Assumed 6.5% for <=250 kW, 6% for >250 (*RI Renewable Energy Growth 2019 Ceiling Price Development Process*)
  - **Change Over Time:** Fed unlikely to raise interest rates again (but unclear when they might fall again), so interest rates assumed flat to be small-c conservative
  - **High/Low Variance Within Policy/Revenue Cases:** +/- 50 basis points
  - **TPO/Host Variance:** For larger scale host systems, assumption is financing w/corporate bonds, which are general obligation in nature and non-recourse to the project. Host-owned residential systems assumed at Mass Solar Loan Program terms (6% during trailing 4 quarters)
  - **Change Between Policy/Revenue Base Cases:** Not varied (in line with Northeast market participant feedback, which does not assume more costly debt interest for lack of a long-term contract/tariff)
- **Debt Tenor**
  - **Initial Estimate (Associated w/Fully Unhedged):** Less hedging leads to shorter expected tenors – smallest amount is 7 years for <=250 kW, and 10 years for >250 kW (break point is in line w/ *RI Renewable Energy Growth 2019 Ceiling Price Development Process* and *Developing a Post-1,600 MW Solar Program*)
  - **Change Over Time:** No change
  - **High/Low Variance Within Policy/Revenue Cases:** +/- 2 years
  - **TPO/Host Variance:** +3 years for Host financed systems (in line w/*Developing a Post-1,600 MW Solar Program* assumption of general obligation corporate bonds, per discussion below), except for
  - **Change Between Policy/Revenue Base Cases:** 10/12 years for Unhedged Commodity/Hedged Incentive, and 15 years for all sizes associated w/Hedged Commodity & Incentive

Detailed Draft NJ Solar Financing Assumptions (3)

- **<u>After-Tax Equity IRR (Levered)</u>**
  - **Initial Estimate (for Hedged Commodity & Incentive case):** 9.4% (from 2019 *RI Renewable Energy Growth 2019 Ceiling Price Development Process*)
  - **Change Over Time:** Assumed to drop 0.4% from highest (30%) to lowest (10%) ITC (roughly in line w/Northeast market participant feedback, rounded up from 0.35%). Drops 0.2% during ITC transition, and remaining 0.2% in 2022
  - **High/Low Variance Within Policy/Revenue Cases:** +/- 100 basis points
  - **TPO/Host Variance:** While TPO based on typical third-party sponsor/tax equity finance, host-owned systems larger than 25 kW assumed based on corporate hurdle rates of 12% (<=25 kW assumed equal to 6% Mass Solar Loan Program value discussed previously)
  - **Change Between Policy/Revenue Base Cases:** +50 basis for Unhedged Commodity/Hedged Incentive, and additional +50 for Unhedged Commodity & Incentive

TI Capacity and Incentives Methodology

Prepared by Cadmus and Sustainable Energy Advantage for the NJ Board of Public Utilities, August 2019

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Calculating Transition Incentive Market Shares

Monthly build rates per size bin are allocated to specific project types as follows

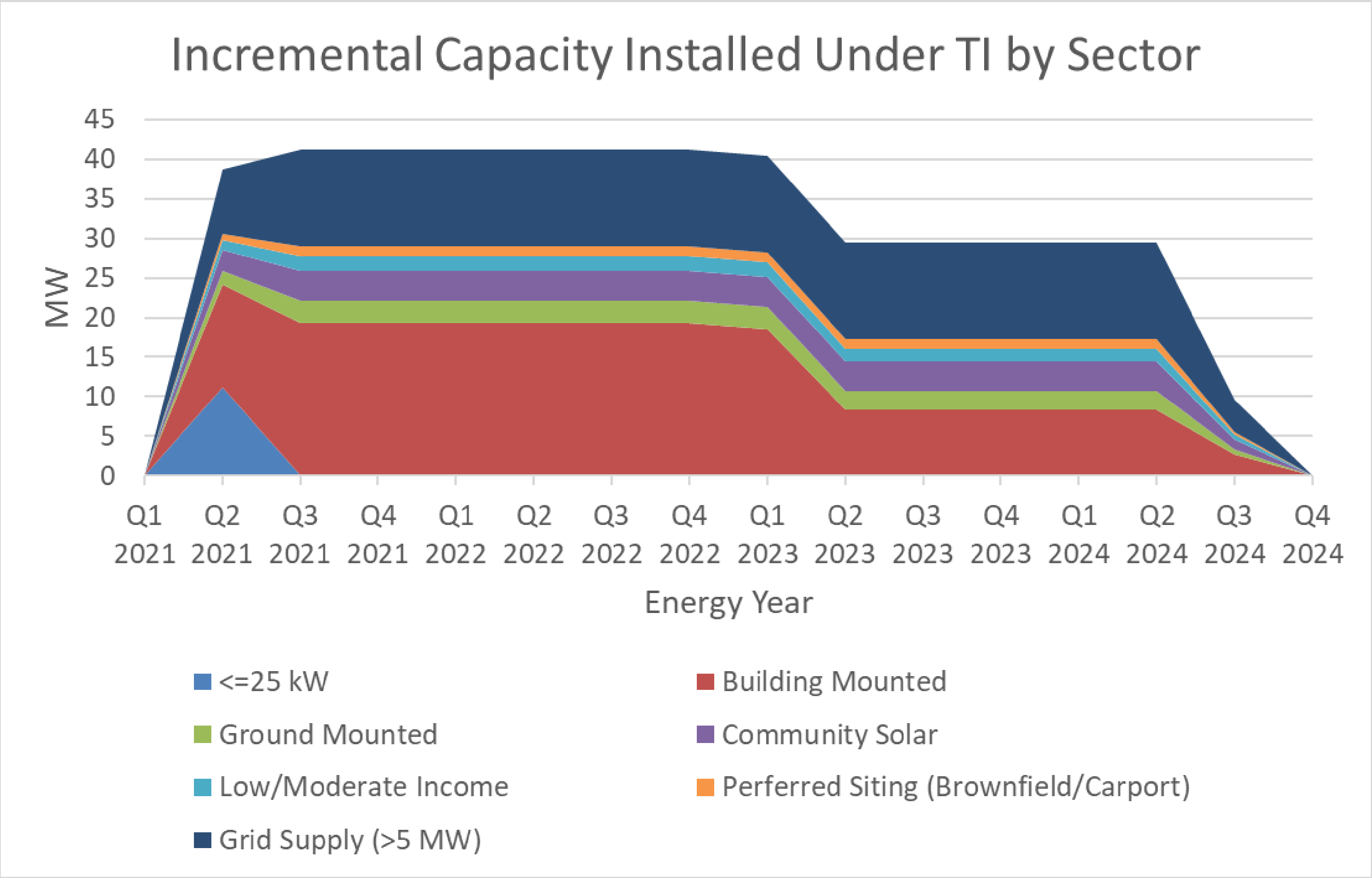
Resource Block	Size Bin	Market Share per Size Bin					
Residential Roof Mount	<25 kW	90%					
Small Commercial Roof Mount	<25 kW	10%					
Medium Commercial Roof Mount	25 - 250 kW		95%				
Medium Commercial Roof Mount (LMI)	25 - 250 kW		5%				
Medium Commercial Building Mounted	250 - 500 kW			90%			
Medium Commercial Ground Mounted	250 - 500 kW			10%			
Large Commercial Building Mounted	500 - 1000 kW				65%		
Large Commercial Ground Mounted	500 - 1000 kW				10%		
Small Landfill/Brownfield	500 - 1000 kW				5%		
Small Community Solar	500 - 1000 kW				10%		
Small Community Solar (LMI)	500 - 1000 kW				10%		
Very Large Building Mounted	1000 - 5000 kW					40%	
Very Large Building Mounted Community Solar	1000 - 5000 kW					10%	
Medium Community Solar	1000 - 5000 kW					10%	
Medium Community Solar (LMI)	1000 - 5000 kW					5%	
Large Community Solar	1000 - 5000 kW					10%	
Large Community Solar (LMI)	1000 - 5000 kW					5%	
Large Landfill/Brownfield	1000 - 5000 kW					5%	
Large Ground Mounted	1000 - 5000 kW					15%	
Very Large Ground Mounted (Fixed Tilt)	5000+ kW						100%

TI Incentive Rate Methodology

We categorize project types into the following Incentive Groups:

Project Type	Incentive Group
Residential Roof Mount	<25 kW
Small Commercial Roof Mount	
Medium Commercial Building Mounted	Building Mounted
Large Commercial Building Mounted	
Medium Commercial Roof Mount	
Very Large Building Mounted	
Very Large Ground Mounted (1-Axis Tracking)	Ground Mounted
Very Large Ground Mounted (Fixed Tilt)	
Medium Commercial Ground Mounted	
Large Commercial Ground Mounted	
Large Ground Mounted	
Small Community Solar	Community Solar
Medium Community Solar	
Large Community Solar	
Very Large Building Mounted Community Solar	
Small Community Solar (LMI)	Low/Moderate Income
Medium Community Solar (LMI)	
Large Community Solar (LMI)	
Medium Commercial Roof Mount (LMI)	
Small Landfill/Brownfield	Preferred Siting
Large Landfill/Brownfield	
Very Large Carport	
Large Commercial/Campus Lot Carport	
Medium Commercial Lot Carport	

Incremental Transition Incentive MW Forecast



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Calculating Production & Comparison to Cost Cap

- To construct TI rates for policy paths involving an SREC market, we utilize a linear equation to match the highest cost Incentive Group's COE with the NPV provided by the incentive over the duration of the incentive term
  - The equation takes a known SACP level during the "kink" period and solves for an SACP level after the kink period that will result in the required TI NPV (given assumptions regarding the % of time the market will be at the cap and floor)
  - The NPV of the TI is calculated from a financer's perspective, which assumes reduced revenue per SREC relative to actual expected revenue.
  - For policy paths involving SREC factors, factors are assigned to each Incentive Group such that the incentive NPV is equal to the group's weighted average COE
  - For policy paths that do not involve a SREC factors, we create incentives that can support the highest cost Incentive Group to preserve project diversity
- Each Incentive Group's COE represents the weighted average of the COE of the project types in the Incentive Group, based on their relative market share.
  - Each project type's COE is a weighted average of the 3rd-party-owned and host-owned COE, based on assumed ownership distributions per project type (see table).
  - We assume the lowest incentive value to be at Class I REC prices (assumed at $7 per REC)

Project Type	% Third Party Ownership
Residential Roof Mount	73%
Small Commercial Roof Mount	73%
Medium Commercial Roof Mount	48%
Medium Commercial Roof Mount (LMI)	100%
Medium Commercial Lot Carport	48%
Medium Commercial Building Mounted	58%
Medium Commercial Ground Mounted	80%
Large Commercial Building Mounted	52%
Large Commercial Ground Mounted	80%
Large Commercial/Campus Lot Carport	52%
Small Landfill/Brownfield	100%
Small Community Solar	100%
Small Community Solar (LMI)	100%
Very Large Building Mounted	65%
Very Large Building Mounted Community Solar	95%
Very Large Carport	65%
Medium Community Solar	100%
Medium Community Solar (LMI)	100%
Large Community Solar	100%
Large Community Solar (LMI)	100%
Large Landfill/Brownfield	100%
Large Ground Mounted	80%
Very Large Ground Mounted (Fixed Tilt)	100%
Very Large Ground Mounted (1-Axis Tracking)	100%

Cost Cap Model Methodology

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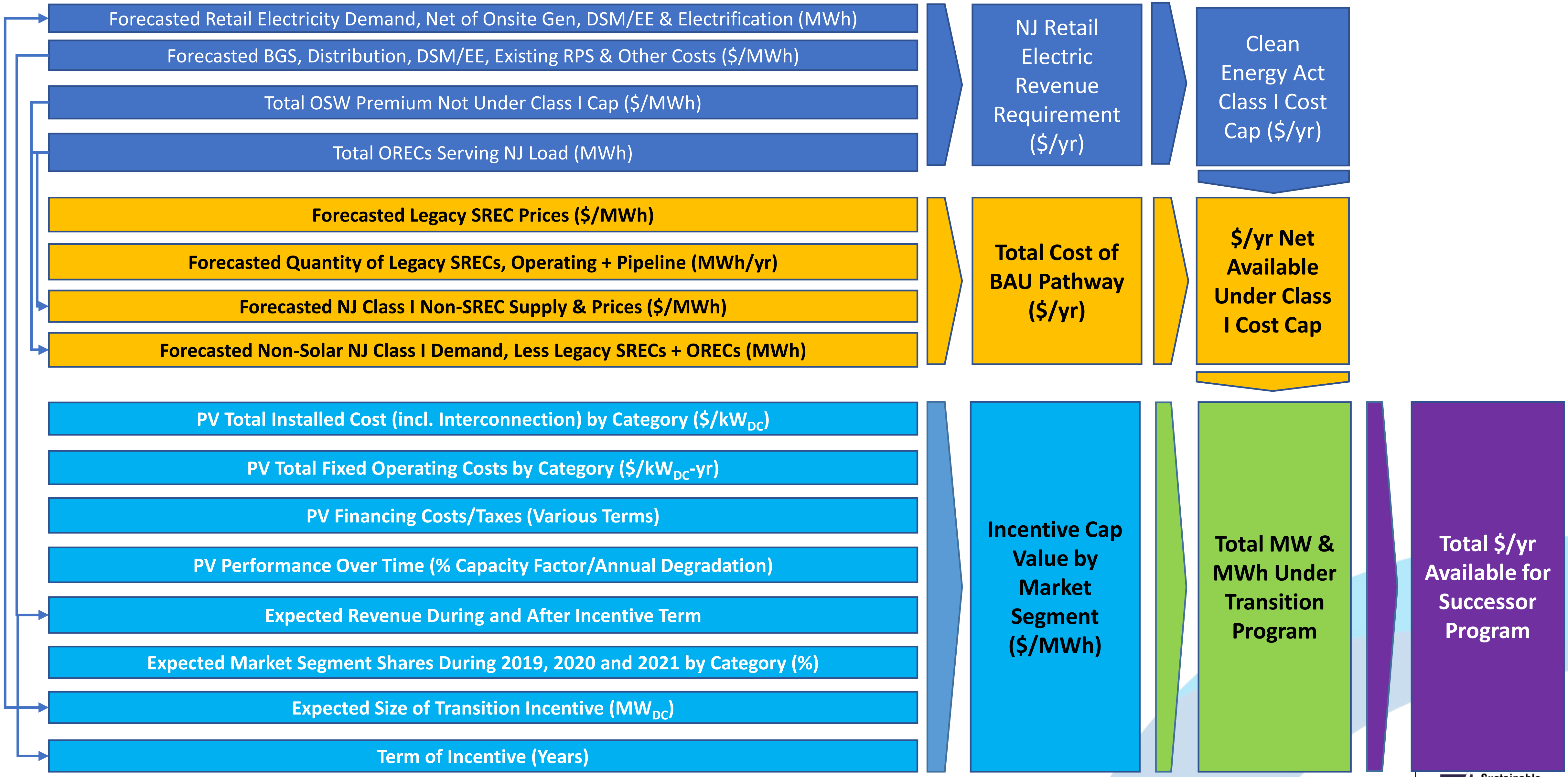
NJ Solar Transition Phase I Analysis Overview



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Part I: Calculating Clean Energy Act Class I Cost Cap

[Total Forecasted Retail Electric Demand (Net of On-Site Generation, DSM/EE & Electrification) (MWh) × Total Forecasted BGS, Distribution, DSM/EE, RPS Class I/II, SREC & Other Costs ($/MWh)] + [Total OSW Premium Not Under Class I Cap ($/MWh) / Total ZEC Premium Not Under Cost Cap × Total ORECs/ZECs Serving NJ Load (MWh)] =

NJ Retail Electric Rev. Req’t ($/yr) × Cost Cap %s by Year = **Clean Energy Act Class I Cost Cap by Year**

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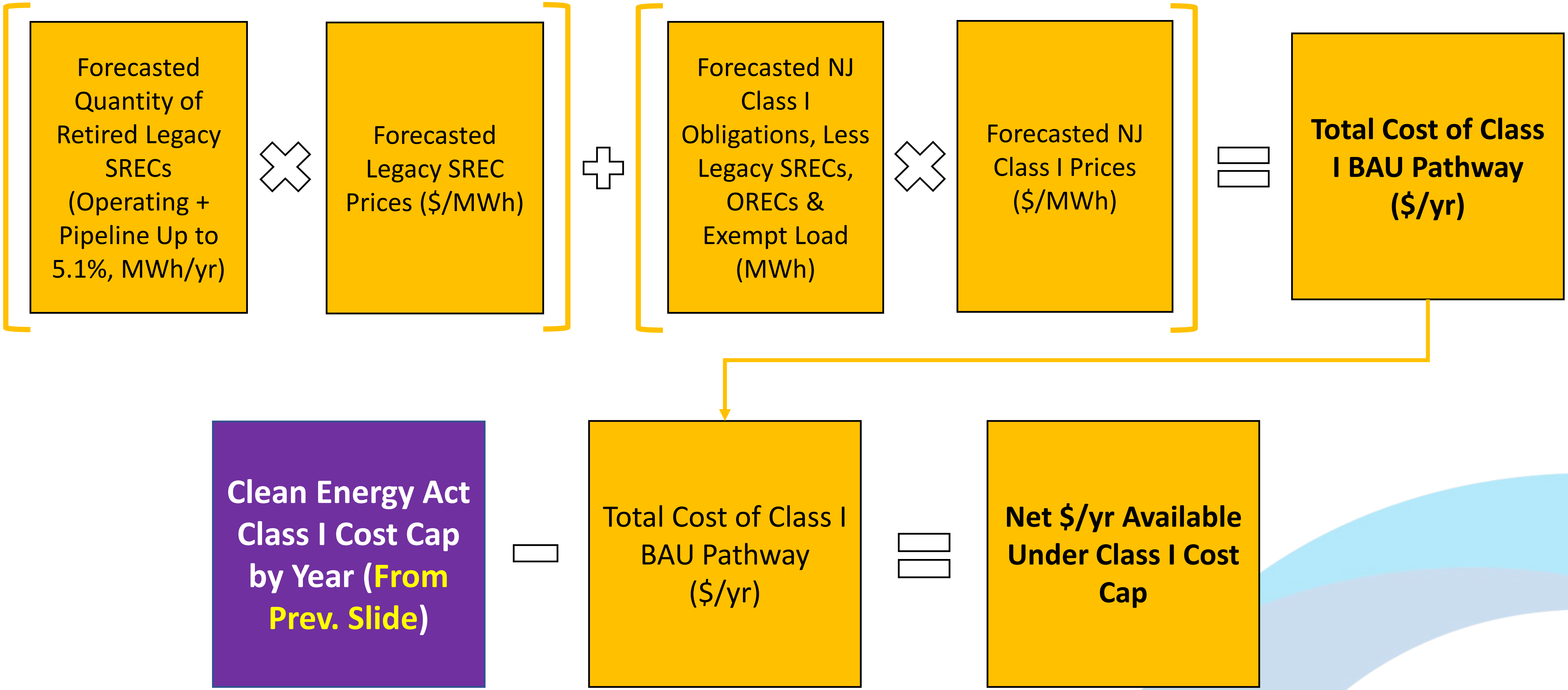
Part II: Calculating Cost Cap Headroom Available to NJ Solar Transition



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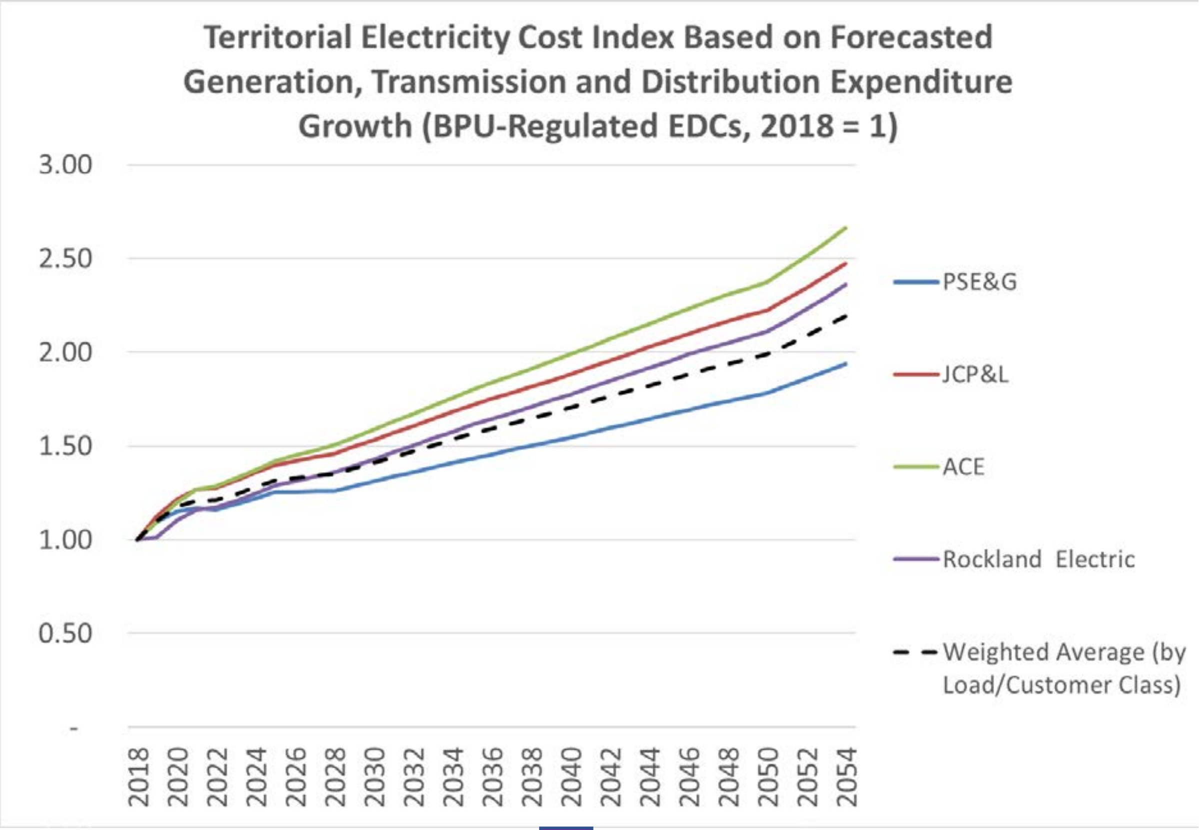
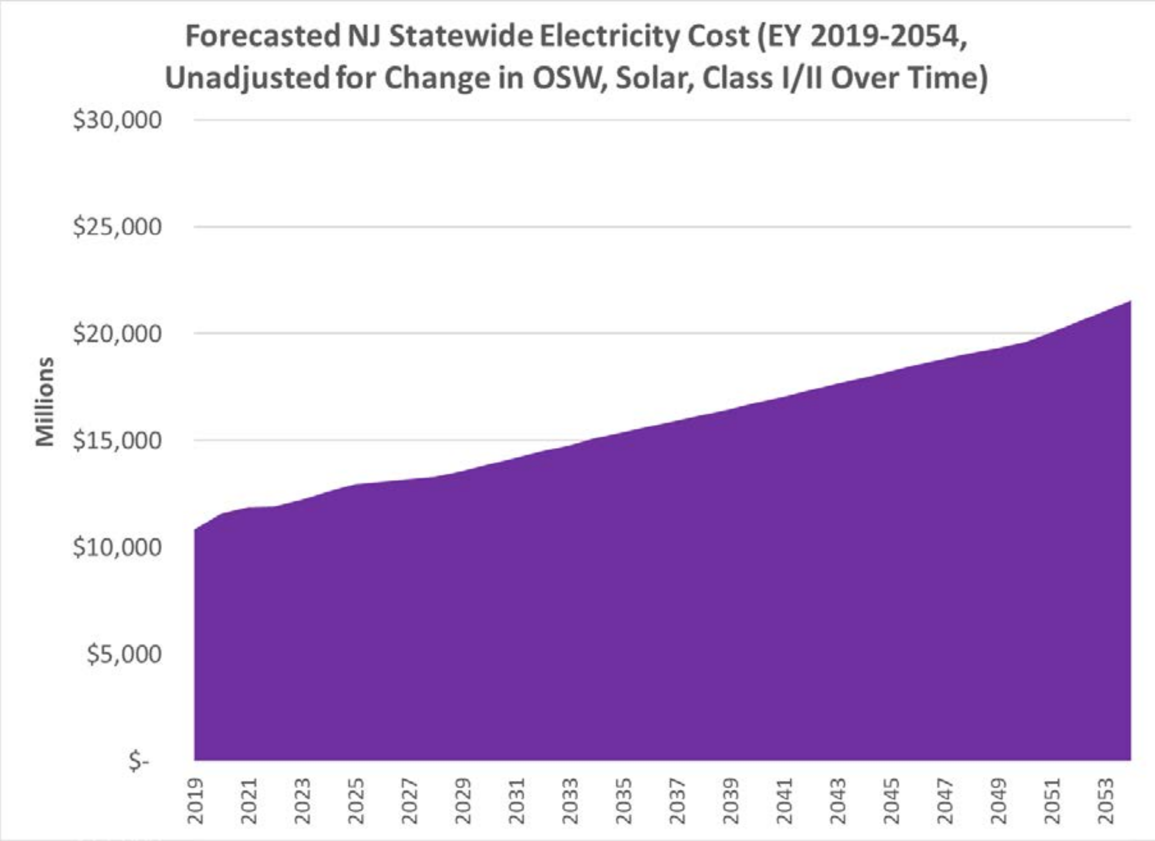
Step 1: Calculate 1st Cut Total NJ Electricity Cost

- Key Modeling Principles & Assumptions for Estimating Total Cost
  - Short of engaging in production cost modeling, growth index of electric distribution company (EDC) rates is best proxy for future statewide electricity cost
  - Index is multiplied by **$9.84B** (total cost of electricity for all providers in NJ found in EIA Form 861 data for EY 2018)
  - Reductions in sales from DSM/EE assumed to be reconciled, permitting full EDC lost revenue recovery
- Forecasted EDC rates = function of forecasted energy, capacity, transmission and distribution
  - Energy and Capacity: based on ICF RGGI re-entry analysis for NJ DEP in December 2018
    - Energy assumed to **grow 0.6%/year through 2030** (Assumed at same rate thereafter)
    - Capacity prices **fall 2.8%/year through 2030** (Assumed flat thereafter)
  - Transmission and Distribution: based on EIA AEO 2019 forecasted transmission and distribution prices for the RFC-East region

    T&D index expected to **grow at 3.5%/year through 2050** (assumed same rate through 2054), in line with significant historical and expected growth in T&D investment in NJ and nationwide
  - Forecasted rates indexed to 2018 = 1, and weighted by residential/non-residential customer share
- Results in revenue requirement index based on all four BPU-regulated EDCs, which is rolled into a statewide index and multiplied by EY 2018 total electricity cost
- High/low scenarios assume +/- 5% annual potential variance in total cost

Step 1: Calculate 1st Cut Total NJ Electricity Cost





Step 2: Calculate Adjustments Based on New/Existing Policies Modified by 2018 Legislation

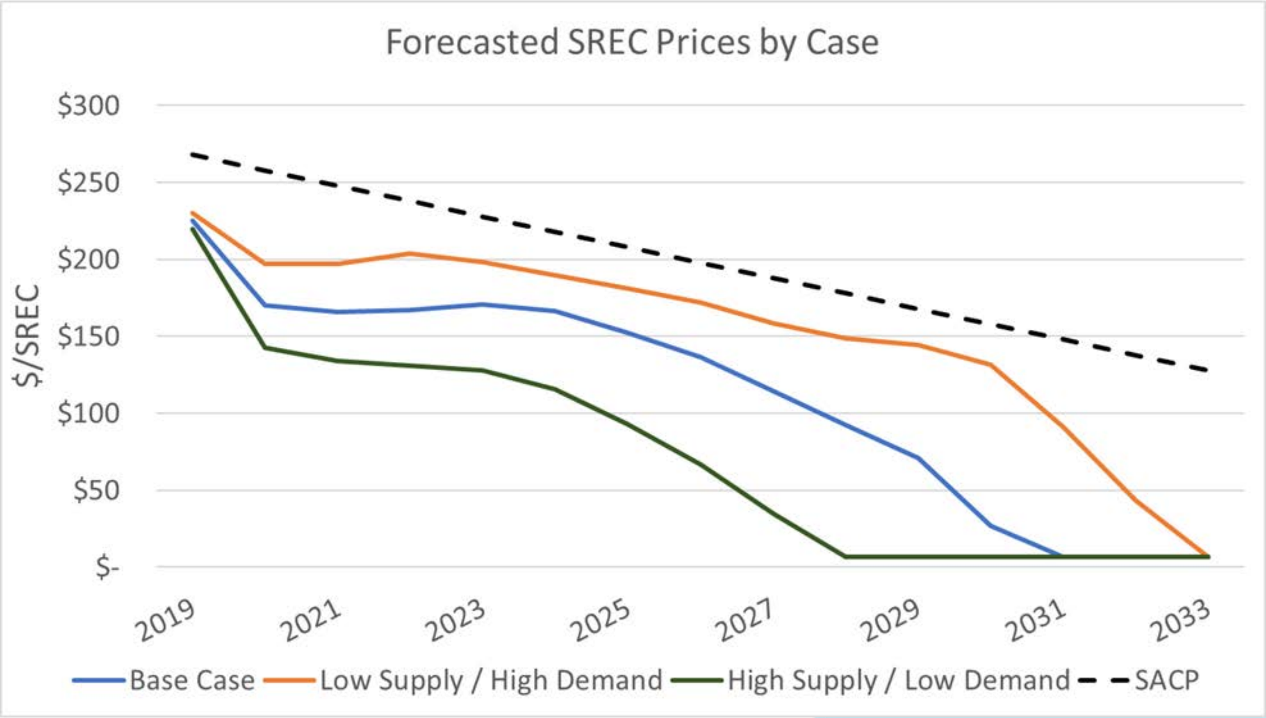
- Several programs created or modified by 2018 energy legislation (and thus are now part of BAU) have significant costs (or significant positive or negative impacts on total cost) that impact the cost cap
  - **Offshore Wind Renewable Energy Certificate (OREC) Program:** 3,500 MW by 2030 program counts as fully accretive to Solar Transition headroom (i.e., totally accretive relative to 2018 baseline, and also excluded from counting under cap)
  - **Legacy SREC Program:** Program cost forecasted to be high through mid-2020s, but set to decline rapidly thereafter. Counts against cap, but also reduces overall cost of electricity as prices and requirements fall below 2018 baseline
  - **Zero Emission Credit (ZEC) Program:** April 18th program approval expected to add $290 million/year for three years to total electricity cost (no increases assumed thereafter, given BAU nature of case). Like ORECs, counts as fully accretive, given $0 impact in 2018 baseline electricity cost value
  - **Non-Solar/OSW Class I:** Requirements expected to significantly expand through 2030 (and rise proportionate with electricity sales/costs thereafter)
- **Most significant long-run dynamics:** increase in net ratepayer costs associated with OREC program, offset by roll-off of Legacy SREC program costs

Step 2a: Calculate OSW Net Ratepayer Cost

- ORECs assumed to act like carve-out (1-for-1 substitution of ORECs for NJ Class I RECs)
  - **Therefore, displacement of Class I RECs by higher-cost ORECs not under cap is <u>more than fully accretive</u> to amount allowed under Class I Cost Cap**
- OSW deployment pathways vary based on aggressiveness of assumed CODs for initial 1,100 MW subject to procurement in CY 2019/EY 2020
- Due to the procurement of Ocean Wind, we assume 1,100 MW reaches commercial operation 10/1/2024
- OSW Resource Costs:
  - Utilized an "average of averages" from a proprietary internal forecast of 20-year OREC contracts by COD year (see next page)
- Calculating OSW production/market revenue/net ratepayer premium
  - **Capacity Factor:** ICF RGGI re-entry analysis assumes 55% capacity factor
  - **Energy & Capacity:** OSW assumed to receive 104% of flat block energy rates and 31% PJM summer capacity credit (See Mills 2018), which were calculated against ICF RGGI re-entry forecast of energy and capacity. Assumed 100% monetized by EDCs on behalf of NJ ratepayers
  - **Net Ratepayer Costs:** OREC costs assumed to be incurred in tranches based on COD, whereas market revenue assumed to be monetized at annual market values

Step 2b: Calculate Legacy SREC/Class I & II Costs

- Clean Energy Act of 2018 mandated extensive changes to Legacy SREC program (***see prior presentation for more***)
- **Total Cost of Legacy SREC Program:** Calculated as product of total retired Legacy SRECs, multiplied by SREC forward prices (***shown at right***), plus any ACP volume (which we only found in the Low Supply / High Demand Scenario)
- **Class I & II RECs:** Forward Class I and Class II REC prices calculated parametrically, assumed to be \$7/MWh and \$5.56/MWh, respectively, in perpetuity based on EY 2019 averages
    - Sensitivities assume (for the "high" Solar Transition budget case) a 25% derate to \$5.25/MWh, while lowest case assume doubling to \$14/MWh
    - Assumption of continuity partially based on observations of substantial and ongoing oversupply in PJM Class I markets (and potential for more as other states consider RPS increases and large-scale solar/wind cost decline)



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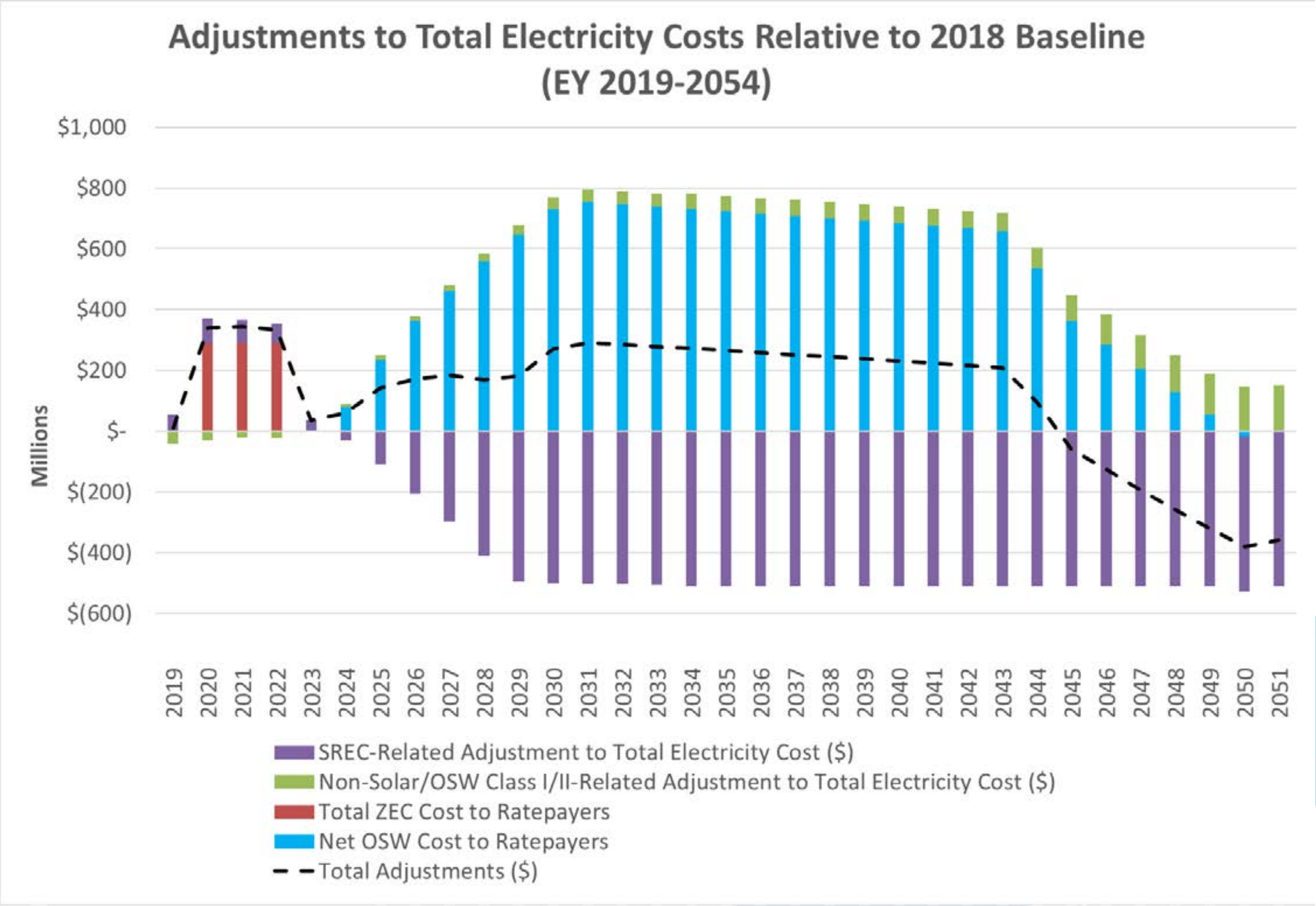
Step 2c: Calculate ZEC Ratepayer Cost

- On April 18, 2019, BPU approved ZEC applications for Hope Creek, Salem One and Two generating stations
  - BPU approved maximum remuneration (**$0.004/kWh**) allowed under An Act Concerning Nuclear Energy for each plant, which BPU noted would be "approximately" $100M per nuclear unit
  - In April 18 order, BPU requested the filing of compliance tariffs, which are likely to indicate full scope of cost to ratepayers
- Cost Cap analysis assumes $290M cost per year for initial 3-year period, with no renewals (given BAU/current law nature of analysis)
- Future drafts of Cost Cap analysis likely to reflect more granular impact of ZEC approvals

Step 3: Calculate Aggregated Adjustments to Base Case Associated with Changes to New/Existing Policies

- OREC program net cost to ratepayers expected to ramp up in 2020s, topping out at **$754 million** in 2031
- Legacy SREC program costs expected to disappear in 2034 after long, slow decline beginning in 2023 (wiping **$509 million** off of total costs relative to 2018 baseline)
- Class I non-solar/OSW costs expected to stay low, but likely to increase substantially in 2040s as OREC/Class I REC substitution slows



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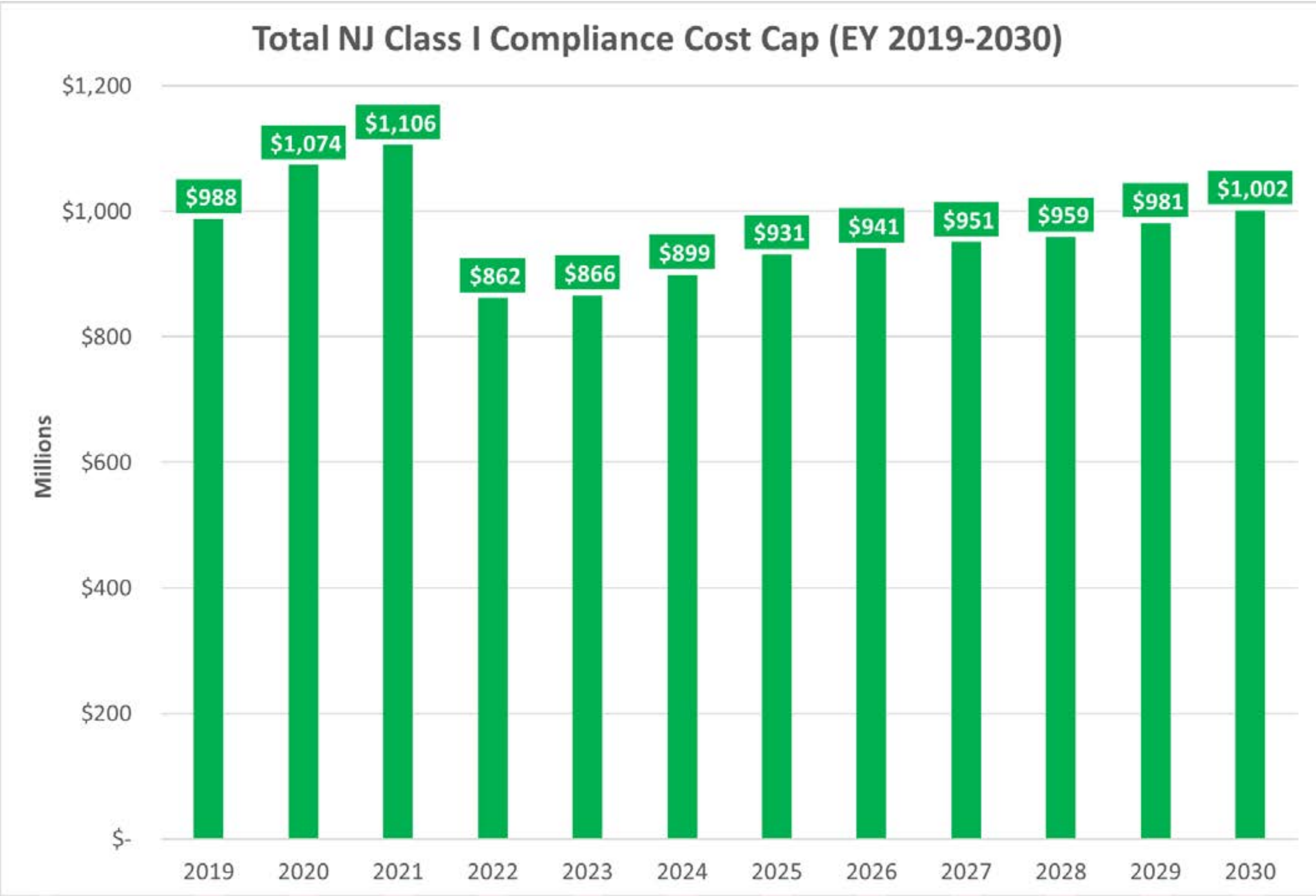
Step 4: Calculate Adjusted Base Case Class I Cost Cap

- EY 2022 referred to in remainder of presentation as "Kink Year" in which Cost Cap significantly contracts year-on-year, (thereby sharply "kinking" downward)
  - In Base Case, Cost Cap assumed to fall by **~$235M from EY 2021 to EY 2022** (shown at right)
- If no banking of cap or net benefits assumed, **<u>the Kink Year becomes year against which Solar Transition funding in preceding years likely needs to be gauged</u>.**



(Highly) Simplified Representation of Transition Size/Cost Calculation

Expected Transition Program Size (MW_{DC})

×

Potential Market Shares by Category (%, 2019-2021, Per Stakeholder Feedback)

×

PV Performance over Useful Life (% Capacity Factor/ Annual Degradation, 2019-2020 COD, from Previous Steps)

×

Term of Transition Incentive (10, 15 or 20 yrs, As Assumed in Each Sensitivity)

=

Total MWs & MWhs Under Transition Program

×

Incentive Req't/ "Incentive Cap Values" by Market Segment ($/MWh, 2019 - 2020 COD, from Prev. Slide)

=

Total Cost of Transition Program

Net $/yr Available Under Class I Cost Cap

−

Total Cost of Transition Program

=

Total $/yr Available for Successor